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ECONOMIC ANALYSIS OF FOAM FRACTURING IN THE DEVONIAN SHALES: PRELIMINARY REPORT

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ABSTRACT

The Department of Energy's Morgantown Energy Technology Center (DOE-METC) has, since 1975, been sponsoring a number of foam fracturing stimulation treatments in the Devonian Shale. Wells stimulated with foam appear to have better potential than hydraulically stimulated wells. This is indicated by a mean initial open flow rate of 329 Mcf/D obtained from nine conventional size pilot treatments in the periphery of the Big Sandy region. In addition, the mean initial open flow rates of three wells that received multiple massive foam treatments has been 394 Mcf/D, even though they were in an old producing area that was partially depleted. The costs of foam stimulation are however definitely higher than those of gelled water fracturing.

This paper presents a preliminary economic analysis of foam treatments. It uses a discounted cash flow method and generalized production decline curves based on actual production data from 25 hydraulically fractured wells in the Devonian Shale (Big Sandy region) of Eastern Kentucky. The results of the study show that gas production from foam fraced wells is economically viable if the resulting production decline curve is similar to that of hydraulically fractured wells with the same initial open flow rates.

INTRODUCTION

It has been established geologically that a potentially significant source of natural gas lies in the Devonian Shales of the Appalachian, Illinois and Michigan Basins of the eastern United States. The shales underlie an area of approximately 250,000 square miles and are distributed in discrete units ranging in thickness from a few feet to about 400 feet. Organic content ranges from 5 to 25 percent by volume and calorie content ranges up to 7 million Btu (MMBtu) per ton of shale. A recent industry study has estimated that the total gas-in-place in the Devonian Shales ranges from 225 to 2,023 trillion cubic feet (Tcf)[1].

References, tables and figures at end of paper.

The technological challenge is to find practical and economic ways to produce this resource. Industry and the Department of Energy (DOE) are presently involved in developing, improving, and evaluating different well stimulation technologies proposed for the exploitation of the Devonian Shales. One of the technologies under consideration is the use of foam as a low-residual fracturing fluid. Foam has been used quite widely in the oil and gas industry for the past five years[2,3,4]. The use of foam fracturing in the Devonian Shale evolved from research at DOE's Morgantown Energy Technology Center (METC) that started in 1975 and was directed at improving gas productivity from new shale wells[5,6]. Together with independent gas producers and in cost sharing contracts with Kentucky West Virginia Gas Co., Consolidated Gas Co., and Columbia Gas System, DOE-METC has conducted a number of both conventional-size (~ 1000 bbls) and massive-size (3000-6000 bbls) foam treatments in stimulating gas production from different stratigraphic units within the Devonian Shale formation[7,8]. Although the number of tests involved and the length of their production history do not yet warrant a statistically-based analysis of the economic viability of foam fracturing, sufficient data has been accumulated to allow for a preliminary evaluation of its economic potential. This paper presents a parametric approach that was used to obtain preliminary insights on the economics of foam fracturing in the Devonian Shales.

FOAM FRACTURING RESULTS

Field data from both conventional size and massive size foam treatments in the Devonian Shales have been accumulated by the DOE-METC in cooperative projects with various gas producers. The location of the foam treatment test wells is shown in Figure 1. Treated intervals include both the Upper and Middle Brown Shale sections of the Appalachian Basin, the New Albany Shale in the Illinois Basin, and the Antrim Shale of the Michigan Basin. Treatment data on these wells, summarized on Tables 1 and 2 are extremely limited and can only be used to obtain preliminary insights. Accordingly, the following observations are offered:

Conventional Size Treatments

1. Foam fracturing in the New Albany Shale failed because the well was plagued with the loss of energy assist medium (nitrogen) into the fractured formation before complete flowback occurred[8].

2. Foam fracturing in the Antrim Shale was able to stimulate gas production in a step out well that was three miles from the gas producing Chester Field. Initial results indicated that after nine days, the well was producing 150 Mcf/D. A substantial water influx of 44 bbl/D accompanied the production[9].

3. Nine of ten foam fracturing treatments conducted in the periphery of the Big Sandy region had initial open flow rates ranging from 103 to 730 Mcf/D with the mean value being 329 Mcf. Only one of these wells, #7246 in Perry County, Kentucky is now producing into a line. Its production has been 17 MMcf in the first year and 18 MMcf in the second year. A second well, #7239, was on line for 19 months but has now been shut in for coal operations. The production history of these wells is shown in Figure 2. The data on six of the wells was developed independently by Columbia Gas Company.

Massive Size Treatments

Ten operationally successful massive foam fracture treatments were performed in four stratigraphic intervals of the Devonian Shale. The tests were conducted in a 3-well farmout area in Lincoln County, West Virginia within an established gas producing region containing 75 old wells[10].

In well No. 20403 at the test site, each of the four massive treatments used foam as the fracturing medium to reduce potential cleanup problems in this low pressure (260 psi) reservoir by taking advantage of the foam's energy assist mechanism. Each treatment design called for 1000 gallons of foam to be injected for each foot of perforated interval so that a comparative analysis of stratigraphic interval production potential could be made. The test intervals and the results of flow tests after stimulation are shown in Table 2 for well No. 20403 and adjacent test wells. Post frac flow rates for four different perforated intervals were 110, 200, 107, and 160 Mcf/D respectively. Its production history is shown in Figure 2.

As an alternative to the use of foam entirely, smaller perforated intervals of the same stratigraphic sections were stimulated with nearly equal volumes of foam and water in three of four available pay zones in the shale well No. 20401. These treatments utilized foam as a spearhead and gelled water as the fracturing medium. Results of Zones 2, 3, and 4 were 111, 80, and 21, respectively (Table 2). A direct comparison of these zones to similar zones in well No. 20403 shows foam to be a better fracturing fluid. In this low pressure reservoir, the foam success was probably due to its greater efficiency in fluid recovery following fracturing since all other factors appear to be similar to the first well. Its production history is shown in Figure 2.

An attempt at optimizing well performance utilizing effective volumes of foam in only two intervals was the objective of the tests in well No. 20402 (Table 2). Post frac open flows of 145 Mcf/D and 139 Mcf/D were measured for Zone 1 and Zone 2, respectively. The sum of these values were taken to represent the well's total potential (i.e. 284 Mcf/D).

METHODOLOGY AND INPUTS

Gas well operators will adopt a new stimulation technology only if it pays them to do so. That is, the return on investment (ROI) of an advanced technology well must meet or surpass the pre-established criteria of the company in order for the well and the technology to be judged a success. Another way of expressing this is that the price required to obtain a pre-established ROI criteria must be equal to or less than the prevailing market price.

For the purposes of this paper, the discounted cash flow (DCF) method has been adopted because it is widely used by major companies as a means of evaluating investments from an economic standpoint. The chief advantages of the DCF method are that the time value of money is considered, and that the calculation is independent of any assumptions about project financing or corporate capital structure. Thus, the results should be equally useful to utilities, independents and self-help operators. Traditionally, the chief objection to DCF has been the complexity of the calculations. This problems has now been overcome by the availability of computer programs such as TRW's ECONGAS.

The Discounted Cash Flow Model

A computer model, ECONGAS, has been developed by TRW based on the definition of DCF. The DCF return on investment is defined as that "r" that solves the equation

$$\sum_t \frac{\text{Net Cash Flow }(t)}{(1+r)^t} = 0 \qquad (1)$$

In other words, the DCF return sets the project's net present value equal to zero. Adapting the above definition to the evaluation of gas drilling ventures results in the following equation used by the model:

$$-D_o - WC - E_o u + \sum_{t=1}^{n} \frac{[Q(t)\ (P_o + t\Delta P)(1-\alpha) - OM_o (1+\beta)^t - D(t)]u}{(1+r)^t} + \sum_{t=1}^{n} \frac{D(t)}{(1+r)^t} + \frac{\gamma D_o}{1+r} + \frac{WC}{(1+r)^n} = 0 \qquad (2)$$

where

P_o = Initial gas price, in \$/Mcf

ΔP = Yearly price increment, in \$/Mcf

$Q(t)$ = Gas production, in Mcf/year

OM_o = Operating and maintenance expenses, in \$/year

β = O&M expenses escalation rate

D_o = Tangible costs that must be depreciated, in \$

$D(t)$ = Depreciation, in \$/year

E_o = Intangible costs that can be expensed, in \$

WC = Pro-rated working capital costs per well, in \$

μ = Income tax retention rate (1-federal tax - state tax rate)

α = Royalty rate

γ = Investment tax credit rate

r = DCF return on investment

n = Life of well, in years

t = Time index, in years

The model is programmed for two modes of operation as follows:

Mode 1: Given a desired return on investment, r, it calculates the gas price schedule, P(t), such that the desired return is received.

Mode 2: Given an initial price, P_o, it computes the resulting return on investment, r.

The model can also be programmed to take inflation (in price and O&M expenses) into account.

Cost Data Input

The cost data for this paper are based on the actual operational costs experienced by Columbia Gas in its field tests of the massive foam fracturing technology. Table 3 gives a detailed account of the actual operational expenses. It may be noted that stimulation costs were \$120,000 out of an intangible cost (including well and well line) of \$317,380 for the optimized treatment well #20402. Not included in Table 3 are additional research related items (amounting to \$403,490) that were charged to the well but which would not normally occur in an operational mode. Columbia Gas has also estimated that further refinements in massive foam fracturing (i.e., a one-stage treatment of all zones) could bring about a cost savings of approximately \$43,000 in a well such as #20402. Thus, the projected intangible cost of massively foam fractured well would be \$274,480, as shown in Table 3.

Cost estimates for smaller foam fracturing treatments ranging from 1,000 bbls to 3,000 bbls were obtained from contractors and are shown on Table 4[3]. To simplify comparison, the costs of a conventional (1,000 bbls) foam frac treatment were assumed to be the same as those projected in Table 3 except for the stimulation cost, which is \$14,157 rather than \$90,000. Thus, the total intangible cost of a conventionally foam fractured well is estimated to be \$198,637.

Production Data and Assumptions

As most of the wells on which the foam treatments have been tested have not yet been put on line, the only production data available are 27 months' of well #7246, 19 months' of well #7239, which has been shut in, and four months' of wells #20403 and #20401. This data is shown in Figure 2. In addition, the data on Table 1 shows that seven out of eight conventional foam treatments in the Big Sandy peripheral region have a mean initial open flow (IOF) of 388 Mcf/D. The average initial open flow of the three massive foam treatment test wells in Lincoln County (adding together all the zones) is 394 Mcf/D.

To perform the DCF analysis required to evaluate the economics of foam fracturing, it was postulated that a definitive relationship exists between a well's measured initial open flow rate (IOF) and its cumulative gas production[12]. This postulate is based in part on the experience of Kentucky-West Virginia Gas Company and Columbia Gas Company that in the Devonian Shale, wells with similar initial open flow rates behave similarly throughout their operating lives. Based on these observations, two generalized well production decline curves were prepared based on eight years of actual production data from 25 hydraulically fractured wells in the Devonian Shale (Big Sandy region) of Eastern Kentucky. Production beyond eight years were obtained by assuming an exponential production decline model. The two curves, representing initial open flow rates of 350 Mcf/D (based on five wells), and 50 Mcf/D to 250 Mcf/D (based on 20 wells) are shown on Figure 3. These curves were used to provide a basis for the preliminary economic evaluation.

Other Economic Assumptions

One of the most important factors influencing the economics of Devonian Shale was the passage of the Natural Gas Policy Act of 1978 (NGPA). The NGPA sets maximum lawful prices for "first sales" by gas producers. The maximum lawful price for most categories of natural gas, among them, "high-cost natural gas" which includes that produced from Devonian Shale, is upwardly adjusted by a monthly inflation factor, plus a real growth factor of 3.5% per year. Initially, the maximum price ceiling was "high cost natural gas" was set at 2.073 \$/MMBtu for December 1978, and is scheduled to increase by approximately two cents per month through 1979[13].

To take this new development into account, the DCF calculations were performed both in constant dollars, as well as assuming three different price escalation scenarios. The three price escalation scenarios are represented by yearly price increments of 0.08 \$/Mcf, 0.14 \$/Mcf and 0.20 \$/Mcf. Corresponding to these price escalation scenarios, the operation and maintenance expenses were postulated to increase at 4%, 7%, and 10% per year respectively. These three escalation scenarios were designed to show the sensitivity of economic criteria such as ROI and required price to varying rates of inflation and are not meant to be treated as forecasts.

A summary of the data and assumptions that were input into the DCF equation (2) is shown in Table 5.

RESULTS OF THE ANALYSIS

The results of the DCF analysis are shown in Figures 4 and 5. Figure 4 shows the prices required to obtain a ROI of 15 percent, given an intangible cost estimate, a price escalation projection, and a production scenario from Figure 3. As discussed before, the intangible cost estimates correspond to a conventional size treatment (stimulation cost = $14,157, intangible cost = $198,637), optimized massive size treatment (stimulation cost = $90,000, intangible cost = $274,480) and actual massive size treatment (stimulation cost = $120,000, intangible cost = $317,380).

The results in Figure 4 indicate that as long as production corresponds to the 350 Mcf/D scenario, the required price will be below the maximum lawful price which is 2.636 $/Mcf in October 1979, at 1150 Btu/Mcf[14]. These prices also look favorable compared to the price of 2.80 $/Mcf that is currently paid for Canadian imports. On the other hand, if production should turn out like the 50-250 Mcf/D scenario, this gas will not be competitive.

The results of computing the return on investment as function as expected price, setting the initial price at 2.40 $/Mcf, are plotted on Figure 5. Here again, the economics of the treatment appear to be highly satisfactory if production follows the 350 Mcf/D scenario and marginal at best if production follows the 50-250 Mcf/D scenario.

CONCLUSION

As is evident from looking at Figures 4 and 5, the economic attractiveness of foam treatments is highly sensitive to the production scenario that is achieved and less sensitive to the costs of stimulation (i.e., intangible costs). This suggests that either conventional or massive foam treatments would be economically attractive if the well production history assumed here for the 350 Mcf/D case can be consistently achieved.

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TABLE 1

TREATMENT DATA ON CONVENTIONAL SIZED

FOAM FRACTURING TESTS

FORMATION TYPE	VOL (GAL)	SAND (LBS)	RATE (bbl/min)	DEPTH (Ft)	PERF. HT. (Ft)	PRODUCTION (IOF) Before/ After/(Mcf/D)	STATE/ COUNTY	COMPANY	WELL NO.	DATE
New Albany Sh	45,000	54,000	25	2186-2320	134	0/15	KY/Christian	Orbit Gas	Clark	November 1976
Antrim Sh	46,000	50,000	25	1508-1580	72	0/150	MI/Ostego	Welch Gas	1-15	December 1977
Br Gr Sh	40,000	40,000	30	2326-2675	350	0/60	KY/Perry	KY-WV Gas	7239	November 1975
Upper/Middle Br Sh	50,000	55,000	25	3174-80 3412-91	86	0/350	KY/Perry	KY-WV Gas	7246	August 1976
Upper/Middle Br Sh	50,000	55,000	25	2560-2580 2730-2790	80	0/103	KY/Perry	KY-WV Gas	1627	April 1977
Upper/Middle Br Sh	50,000	64,000	25	2735-2777 2929-3091	170	0/350	WV/Mason	Reel Energy	D & K #3	April 1978
	59,220	120,000				0/696	KY/Pike	Columbia Gas		September 1978
	--	55,000				0/730	VA/Buchanan	Columbia Gas		March 1979
	21,882	50,000				0/219	KY/Martin	Columbia Gas		March 1979
	35,112	42,000				0/267	KY/Martin	Columbia Gas		December 1978
	--	--				0/130	OH/Lawrence	Columbia Gas		February 1979
	--	--				0/119	KY/Martin	Columbia Gas		February 1979

TABLE 2

TREATMENT DATA ON MASSIVE SIZED
FOAM FRACTURING TESTS

Formation Type	Water Volume (Gal)	Foam Volume (Gal)	Sand (lbs)	Rate (bbl/min)	Depth (ft)	Zone	Perf. Ht. (Ft)	Production (IOF) Before/After (Mcf/D)	State/ County	Contractor	Well No.	Date
Mid Br Sh	40,866	168,000	150,000	20	3400-3560		160	0/180	WV/Jackson	Consolidated Gas	12041	Jan '77
Upper Br.	71,000	284,000	405,000	47.5	2762-2832	4	70	381/160	WV/Lincoln	Columbia Gas	20403	Aug '77
Mid-Grey Upper Br.	67,000	267,000	340,000	48	2954-3230	3	276	103/107	"	"	"	May '77
Middle Br.	75,000	300,000	439,000	47	3409-3651	2	242	95/290	"	"	"	Nov '77
Lower Br.	45,000	179,000	299,000	46.5	3858-4031	1	173	0/110	"	"	"	Jun '76
Upper Br.	53,000	62,000	313,000	25	2662-2720	4	58	0/21	WV/Lincoln	Columbia Gas	20401	Nov '77
Mid-Grey Upper Br.	85,000	57,000	353,000	30	2988-3090	3	102	0/80	"	"	"	Aug '77
Middle Br.	89,000	63,000	322,000	30	3272-3410	2	138	0/111	"	"	"	May '77
Lower Br.	475,000	---	930,000	25.4	3783-3868	1	85	0/110	"	"	"	Aug '76
Mid-Grey Upper Br. Upper Grey	41,000	90,000	290,000	40	2816-3234	2	418	0/139	WV/Lincoln	Columbia Gas	20402	Aug '78
Lower Br. Lower Grey Middle Br.	31,000	150,000	286,000	40	3385-3966	1	581	0/145	"	"	"	Jul '78

TABLE 3

ESTIMATED OPERATIONAL WELL COSTS

	Actual Costs[1]	Projected Costs[2]
Tangibles-Well	$ 38,720	$ 38,720
Casing, tubing, wellhead, misc. material	38,720	38,720
Intangibles-Well	$294,950	$252,050
Company Labor	12,000	12,000
Drilling, Casing Crews, Raw Material, Use of Auto and Hauling	77,590	77,590
Service Rig	18,000	9,000
Logging	4,000	4,000
Perforating	6,000	3,000
Cementing & Float Equipment	10,000	10,000
Site Preparation	26,850	26,850
Transportation	2,000	1,600
Stimulation	120,000	90,000
Interest During Construction	350	300
Stores Expense & Freight	5,070	5,070
Labor Overhead	3,320	3,320
S & A and A & G Overheads	9,770	9,320
Total Well Cost	$333,670	$290,770
Well Line Cost[3]	$ 31,230	$ 31,230
Tangible-Well Line	8,800	8,800
Intangible-Well Line	22,430	22,430
TOTAL TANGIBLES COST	$ 47,520	$ 47,520
TOTAL INTANGIBLES COST	$317,380	$274,480

[1]Includes only costs which would normally be incurred on an operational basis, based on actual expenses for Well 20402.

[2]Operational costs assuming a single stage treatment of all zones.

[3]Average of actual well line costs for Wells 20401, 20402, and 20403.

TABLE 4

PROJECTED STIMULATION COSTS
FOR SEVERAL FOAM TREATMENT SIZES

	1,000 bbl	2,000 bbl	3,000 bbl
Nitrogen[1]	6,232	10,918	15,603
Sand	3,212	6,426	9,639
Surfactant	1,168	2,336	3,504
Proppant Handling	840	1,680	2,520
Pumping (Foam)	800	1,600	1,600
Ton - Mileage	630	1,260	1,890
Blender Charge	560	560	560
Mileage[2] and Delivery[3]	300	537	712
Surfactant Pump	210	210	210
Clay Stabilization	204	408	612
	14,157	25,935	36,947

[1]Based on BHTP of 1200 psi
[2]Based on 100 miles
[3]Based on 10 hours

TABLE 5

INPUTS TO THE DISCOUNTED CASH FLOW PROGRAM

INPUT NAME	SYMBOL	INPUT VALUE	COMMENTS
Gas Price-Initial	P_o	2.40 $/Mcf	Set only when r is computed
Price Increment	ΔP	0.00 $/Mcf	Used in constant dollar scenario
Low		0.08 $/Mcf	Used in low inflation scenario
Medium		0.14 $/Mcf	Used in medium inflation scenario
High		0.20 $/Mcf	Used in high inflation scenario
Gas Production	Q(t)		
IOF = 350 Mcf/D		see Figure 3	
IOF = 50-250 Mcf/D		see Figure 3	
O&M Expenses	OM_o	$1700	
O&M Escalation Rate	β	0%	Used in constant dollar scenario
Low		4%	Used in low inflation scenario
Medium		7%	Used in medium inflation scenario
High		10%	Used in high inflation scenario
Tangible Costs	D_o	$47,520	
Depreciation	D(t)		Double declining balance with switchover to sum of years digits
Intangible Costs	E_o		
Conventional		$198,637	Stimulation = $14,157
Massive-projected		$274,480	Stimulation = $90,000
Massive-actual		$317,380	Stimulation = $120,000
Working Capital	WC	$10,000	
Tax retention rate	μ	51%	Assumes 46% federal income tax and 6% state income tax
Royalty rate	α	12.5%	Assumed to be 12.5% of revenue
Investment Tax Credit	γ	10%	Credited in first year of production
Return on Investment	r	15%	Set only when price is computed
Life of Well	n	30 years	

FIGURE 1

LOCATION OF FOAM TREATMENT TEST WELLS

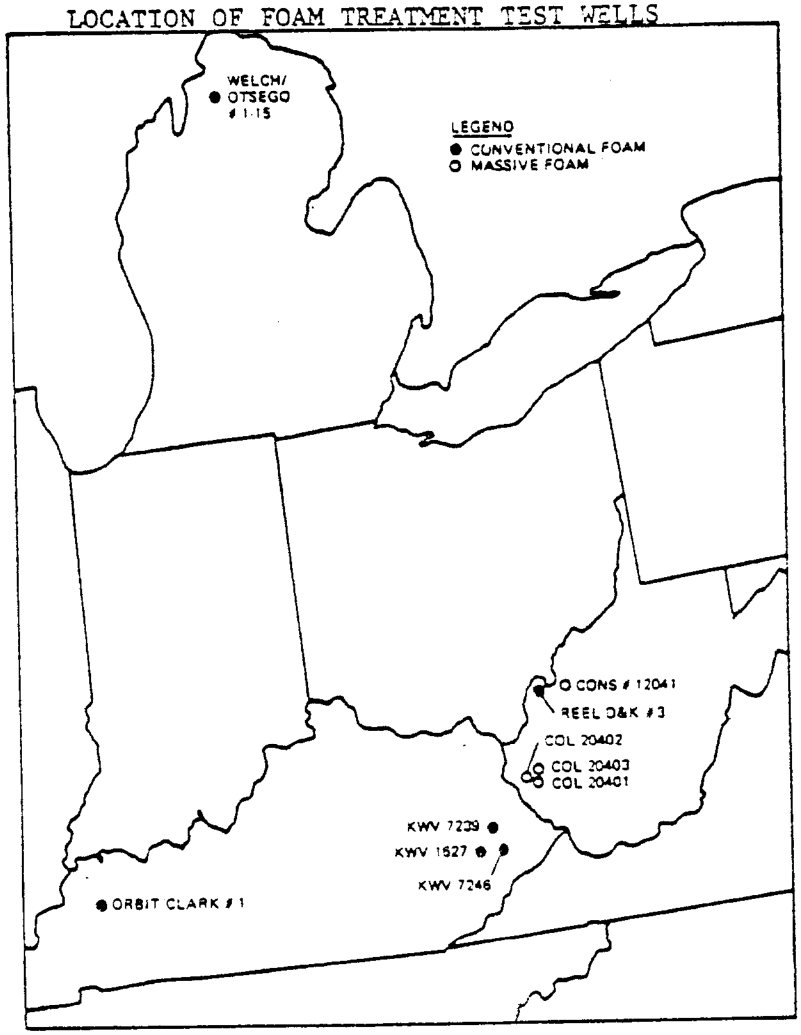

FIGURE 2

GAS PRODUCTION FROM FOAM FRACTURED TEST WELLS

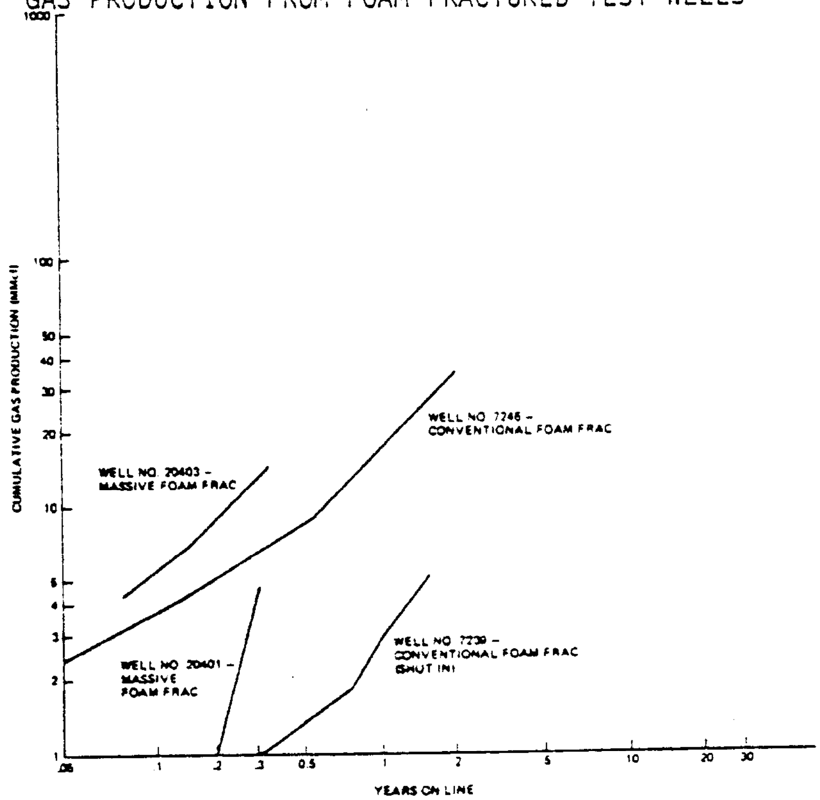

FIGURE 3

GENERALIZED PRODUCTION DECLINE CURVES

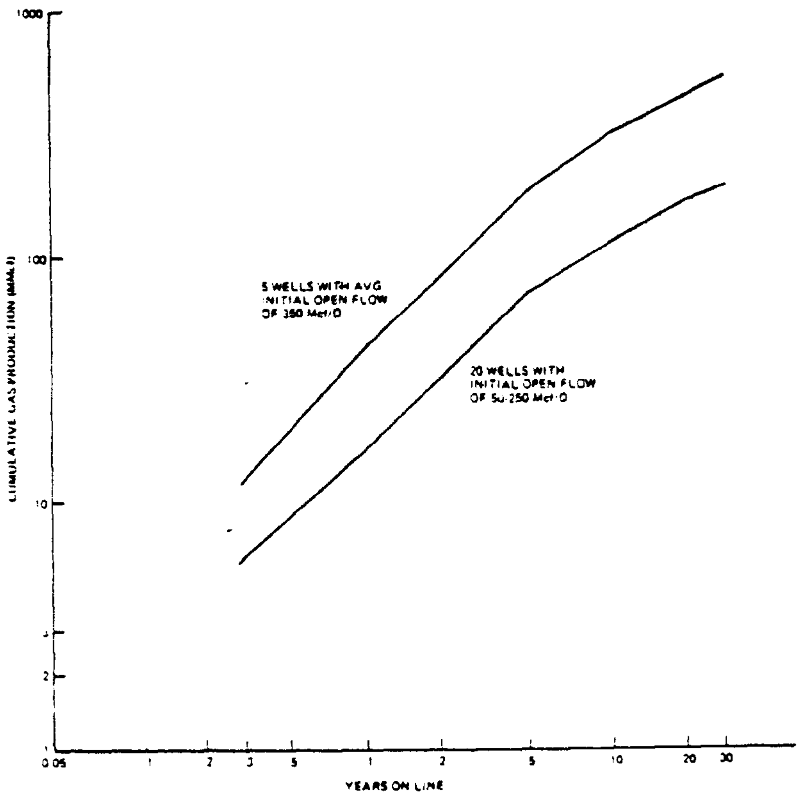

FIGURE 4

REQUIRED PRICE OF FOAM TREATED WELLS
(ROI=15%)

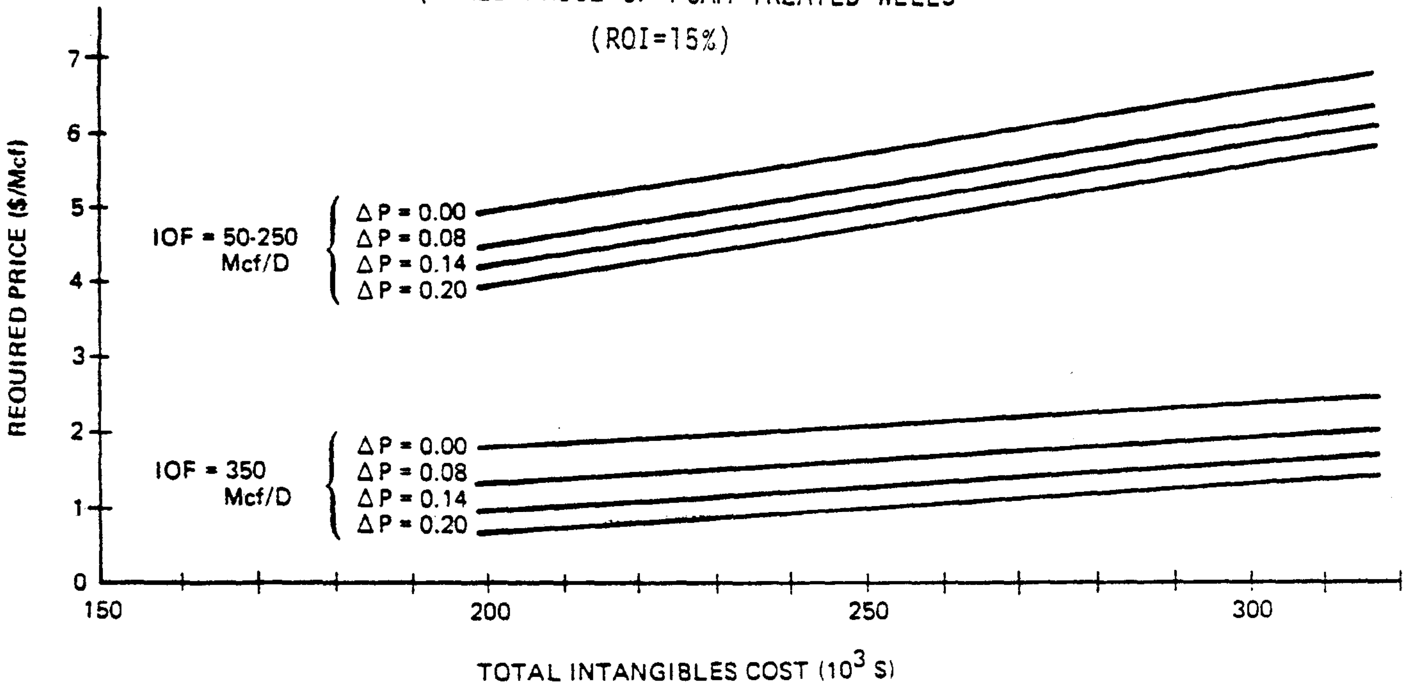

FIGURE 5

RETURN ON INVESTMENT OF FOAM TREATED WELLS
(Initial Price=2.40 $/Mcf)